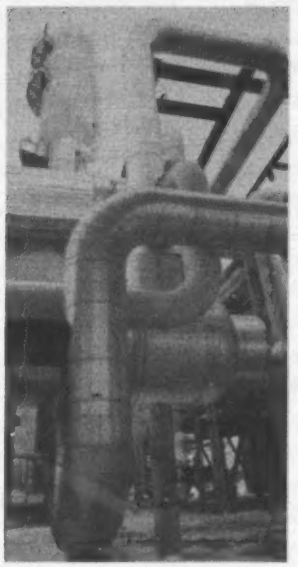
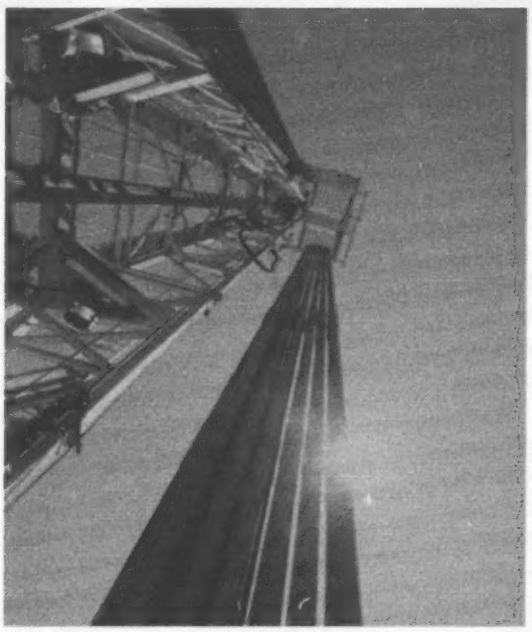
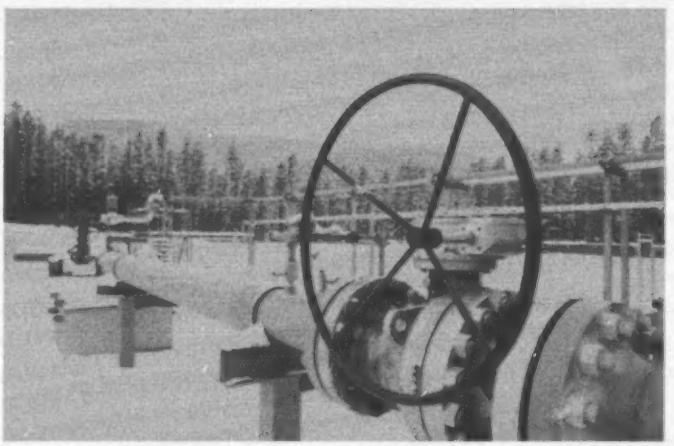
ALBERTA OIL & GAS INDUSTRY QUARTERLY UPDATE







WINTER 2016

Reporting on the period: Sept 23, 2015 to Dec 17, 2015

All about oil and gas

While Alberta and its petroleum sector has endured the hurt of sinking world crude oil prices and continued weak natural gas prices, the province is well positioned to rebound once the cyclical nature of commodity prices eventually recalibrates.

In fact, technological advancement has set the stage for future growth in Alberta's non-oil sands oil and natural gas industry. Until the turn of the last decade, the sun had slowly been setting on Alberta's conventional oil and natural gas industry. Oil production had declined from a peak of 1.43 million barrels per day (bbls/d) in 1973 to a low of around 460,000 bbls/d in 2010.

But things have changed for the better, as increased implementation of long horizontal wells and multistage fracturing in tight oil plays across the province—not to mention improved provincial royalty incentives to encourage drilling—has crude oil drilling activity and production on the upswing.

In fact, the tight oil revolution that began in the U.S. gradually moved north into Alberta, marking the dawning of a new day for oil and natural gas exploration and production in the province.

In Alberta, the technology is being used in an increasing number of oil plays. Among the most advanced plays are the Cardium in west-central Alberta, the Beaverhill Lake Carbonates near Swan Hills and the Viking in east-central Alberta.

More importantly, emerging liquids-rich plays like the Montney and Duvernay shale show great promise. In fact, the Duvernay play may have the most potential going forward.

At the end of 2014, industry giants such as Chevron Canada and Encana reported strong liquids yields, particularly for valuable condensate, and producers are preparing to ramp up activity this year.

The Duvernay is often compared to the prolific Eagle Ford of Texas because they are both shale plays that offer a full spectrum, from dry gas through liquids-rich gas to oil. Many other shale plays, such as the Horn River Basin in B.C. and the Marcellus or Barnett south of the border, are much more gas-focused.

In terms of the potential size of the play area, the richness of the source rock and even some of the early production results, the Duvernay "is well on its way to being as big or bigger than the Eagle Ford," Canadian Discovery has proclaimed.

The increase in horizontal drilling activity is expected to offset the steep decline in Alberta conventional production that would otherwise be expected.

The Alberta Energy Regulator estimates the remaining established reserves of conventional crude oil in Alberta to be 1.8 billion barrels, representing more than one-third of Canada's remaining conventional reserves. This increase of 1.6 per cent over the 2013 estimate is from all reserve adjustments less production in 2014.

The province's production of conventional crude oil totalled 215 million barrels in 2014, an increase of 1.3 per cent.

The province is also the largest contributor to Canadian oil and equivalent production and is the only contributor of upgraded and non-upgraded bitumen, which are the marketed components of raw bitumen production.

Alberta is Canada's largest producer of marketable natural gas. In 2013, Alberta produced 69 per cent of Canada's total production, down from 70 per cent in 2012.

In 2014, total marketable natural gas production in Alberta, including unconventional production, increased by 2.3 per cent to 287.3 million cubic metres per day from 280.9 million cubic metres per day.

Canada is the third-largest natural gas producer in the world, with the majority of the country's gas being produced in Alberta. According to provincial figures, at the end of 2012, remaining established reserves of conventional natural gas stood at 33 trillion cubic feet (tcf), while remaining established coalbed methane gas reserves stood at 2.4 tcf. The province estimates the remaining ultimate potential of marketable conventional natural gas at 74 tcf.

Although conventional natural gas remains a very important part of Alberta's natural gas supply, horizontal drilling and multistage fracturing now allow for development of natural gas from a new source—unconventional natural gas resources. ■

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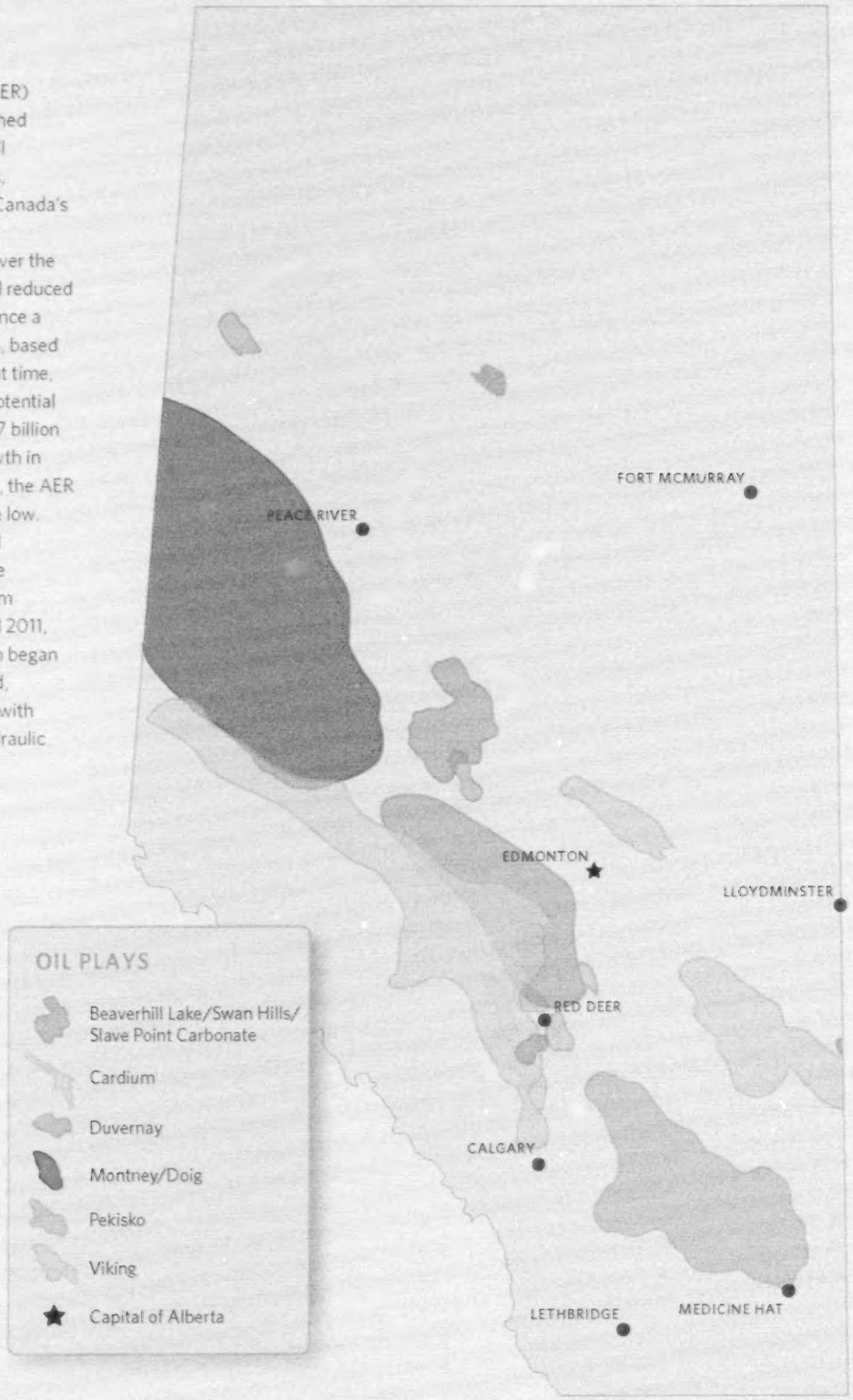
NOTE: This publication contains information about Alberta's oil and gas industry, excluding the oil sands. For information on the oil sands, please refer to the *Alberta Oil Sands Industry Quarterly Update* on this website.

OIL PLAYS

The Alberta Energy Regulator (AER) estimates the remaining established reserves of conventional crude oil in Alberta to be 1.8 billion barrels, representing about one-third of Canada's remaining conventional reserves.

Though the pace has slowed over the past year due to low oil prices and reduced activity, it's expected to resume once a market correction occurs. In 1994, based on the geological prospects at that time, the AER estimated the ultimate potential of conventional crude oil to be 19.7 billion barrels. Given recent reserve growth in low permeability, or tight oil plays, the AER believes that this estimate may be low.

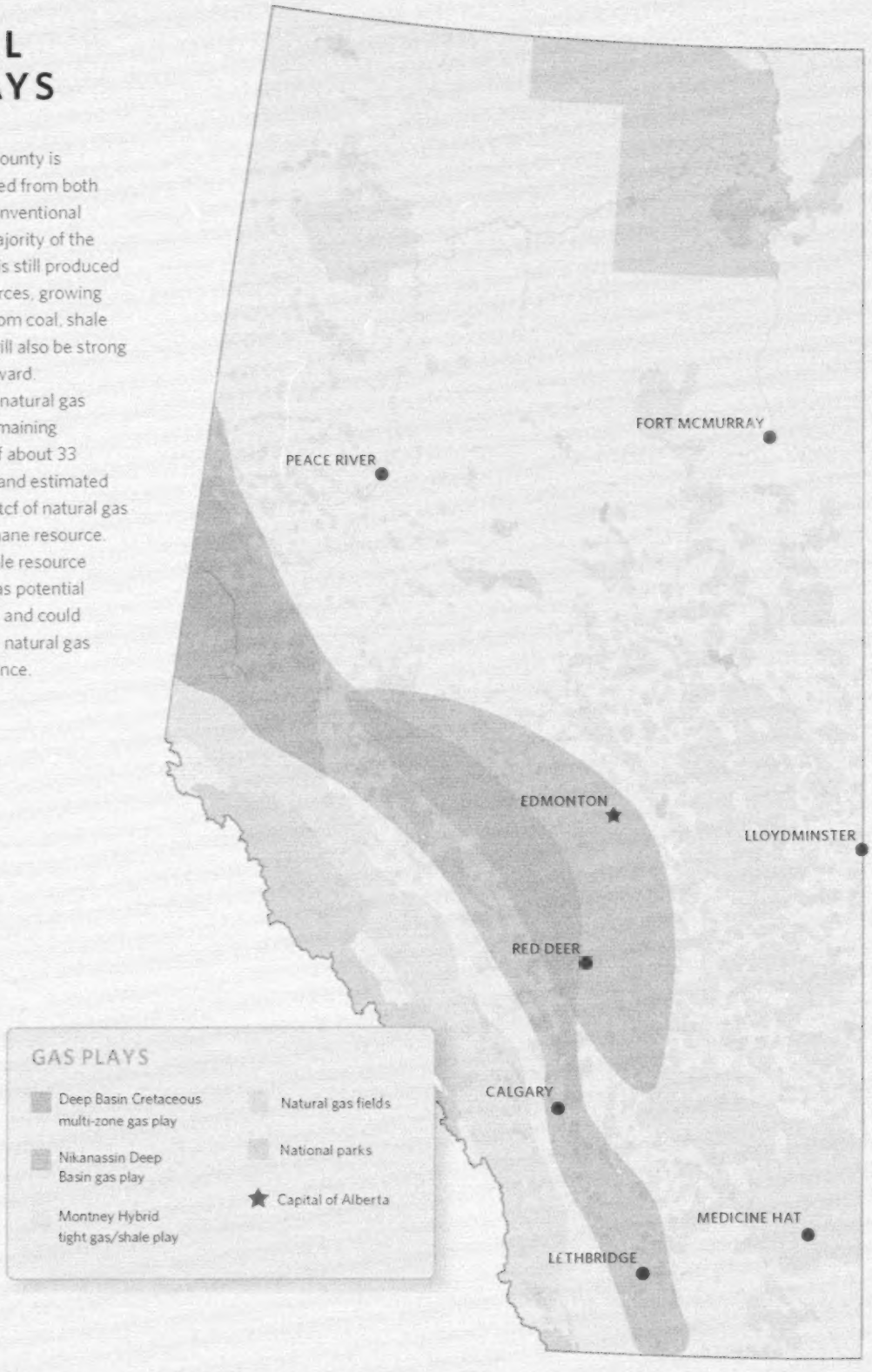
Starting in 2010, total crude oil production in Alberta reversed the downward trend that was the norm since the early 1970s. In 2010 and 2011, light-medium crude oil production began to increase as a result of increased, mainly horizontal, drilling activity with the introduction of multistage hydraulic fracturing technology.



NATURAL GAS PLAYS

Alberta's natural gas bounty is plentiful and is produced from both conventional and unconventional reserves. While the majority of the province's natural gas is still produced from conventional sources, growing natural gas volumes from coal, shale and tight formations will also be strong contributors going forward.

Alberta has a large natural gas resource base, with remaining established reserves of about 33 trillion cubic feet (tcf) and estimated potential of up to 500 tcf of natural gas from the coalbed methane resource. In addition, a large-scale resource assessment of shale gas potential in Alberta is underway and could significantly add to the natural gas prospects for the province.



GOVERNMENT UPDATE

Alberta Government

CLIMATE LEADERSHIP PLAN WILL PROTECT ALBERTANS' HEALTH, ENVIRONMENT AND ECONOMY

Alberta's Climate Leadership Plan accelerates the transition from coal to renewable electricity sources, puts a price on carbon pollution for everyone and sets emissions limits for the oil sands.

Other measures include broad programs to improve energy efficiency, support green technological innovations, reduce methane and provide support to ensure that families and small businesses are protected. (View the news conference.)

"Responding to climate change is about doing what's right for future generations of Albertans—protecting our jobs, health and the environment. It will help us access new markets for our energy products and diversify our economy with renewable energy and energy efficiency technology. Alberta is showing leadership on one of the world's biggest problems, and doing our part," Premier Rachel Notley said.

The plan is based on the advice of the Climate Change Advisory Panel, led by Andrew Leach, which heard from thousands of individual Albertans and stakeholder groups this fall.

"I thank the panel members and the many Albertans, including Indigenous people, industry, environmental groups, municipalities and other partners and stakeholders, for their contribution. This is the right plan for our province, and now is the right time to implement it," said Shannon Phillips, minister of environment and parks.

On the advice of leaders from the provincial energy industry and from civil society, the government will legislate an overall oil sands emissions limit. The province will grow its economy by applying technology to reduce the carbon output per barrel, which is what this limit will promote.

"The announcement is a significant step forward for Alberta. We appreciate the strong leadership demonstrated by Premier Notley and her government. The framework announced will allow ongoing innovation and technology investment in the oil and natural gas sector. In this way, we will do our part to address climate change while protecting jobs and industry competitiveness in Alberta," said Murray Edwards, chair, Canadian Natural Resources Limited.

Ed Whittingham, executive director of the Pembina Institute, said Alberta is now taking its rightful place as a leader on the world stage.

"Premier Notley promised Albertans leadership on the issue of climate change and she and her government have delivered. This is the right thing to do for both for our environment and our economy. The world needs more of this kind of leadership from major energy-producing jurisdictions if we are to avoid dangerous climate change," he said.

ADAPTING TO A LOW-CARBON ECONOMY

Alberta's new climate change plan includes achievable carbon pollution reduction measures, while using revenues from the plan to help the province adapt and thrive in a lower carbon economy.

Electricity and renewables

- Alberta will phase out all pollution created by burning coal and transition to more renewable energy and natural gas generation by 2030.
- Three principles will shape the coal phase-out: maintaining reliability, providing reasonable stability in prices to consumers and business, and ensuring that capital is not unnecessarily stranded.
- Two-thirds of coal-generated electricity will be replaced by renewables—primarily wind power—while natural gas generation will continue to provide firm base load reliability.
- Renewable energy sources will comprise up to 30 per cent of Alberta's electricity production by 2030.

Carbon pricing

- A price on carbon provides an incentive for everyone to reduce greenhouse gas pollution that causes climate change.
- Alberta will phase in this pricing in two steps:
  - $20/tonne economy-wide in January 2017
  - $30/tonne economy-wide in January 2018
- An overall oil sands emission limit of 100 megatonnes will be set, with provisions for new upgrading and cogeneration.

Methane reduction

- In collaboration with industry, environmental organizations and affected First Nations, Alberta will implement a methane-reduction strategy to reduce emissions by 45 per cent from 2014 levels by 2025.

Revenue neutral

- One hundred per cent of proceeds from carbon pricing will be reinvested in Alberta.
- A portion of collected revenues will be invested directly into measures to reduce pollution, including clean energy research and technology, green infrastructure such as public transit, and programs to help Albertans reduce their energy use. ➤

GOVERNMENT UPDATE CONTINUED

- Other revenues will be invested in an adjustment fund that will help individuals and families make ends meet; providing transition support to small businesses, First Nations, and people working in affected coal facilities.

"We are going to do our part to address one of the world's greatest problems. We are going to put capital to work, investing in new technologies, better efficiency and job-creating investments in green infrastructure. We are going to write a made-in-Alberta policy that works for our province and our industries and keeps our capital here in Alberta," said Premier Rachel Notley.

STATEMENT FROM PREMIER NOTLEY ON KEYSTONE XL

Premier Rachel Notley issued the following statement on November 6, 2015, on the U.S. decision regarding the proposed Keystone XL Pipeline:

"Though I am not surprised by the news coming from the White House this morning, as we have anticipated this announcement for some time, I am disappointed by the way the U.S. government chose to characterize our energy exports.

"The decision today underlines the need to improve our environmental record and reputation so that we can achieve our goal of building Canada's energy infrastructure, including pipelines to new markets.

"This highlights that we need to do a better job, and that's why I'm so pleased about the work that is ongoing towards a new climate change plan for Alberta. We're working hard with stakeholders, and we intend to act decisively to increase the likelihood of getting our product to tidewater.

"I spoke with Prime Minister Trudeau this morning about building this infrastructure, which should continue to be a national priority. I reinforced that both the Alberta and Canadian economies need infrastructure that get Alberta's energy resources to tidewater, and he agreed that we need to work collaboratively.

"Canada can be a global source of environmentally responsible energy through better environmental policies, and Alberta will act to help make that happen in partnership with Canada's new federal government.

"And then we hope that future energy infrastructure projects will be debated on their own merits.

"Canada currently exports over three million barrels a day to the U.S., and those exports will continue. Our trading relationship with the United States is of fundamental importance to Alberta, and we will work to build on it.

"Alberta's energy industry is important to families here and across the country, and I will work hard every day to support its sustainability."

PROVINCE BUDGETING FOR LOWER NON-RENEWABLE RESOURCE REVENUE

The Alberta government is forecasting total non-renewable resource revenue to plunge to $2.77 billion for the 2015-16 fiscal year, nearly 70 per cent lower than the $8.95 billion collected in 2014-15.

The Government of Alberta forecasts a budget deficit of $6.1 billion for the fiscal year that ends on March 31, 2016. It plans to run deficits until 2018-19, then expects to post a balanced budget in 2019-20.

Non-renewable resource revenue in 2015-16 will account for 6.3 per cent of total revenue, though its share is expected to grow to 9.1 per cent by 2017-18.

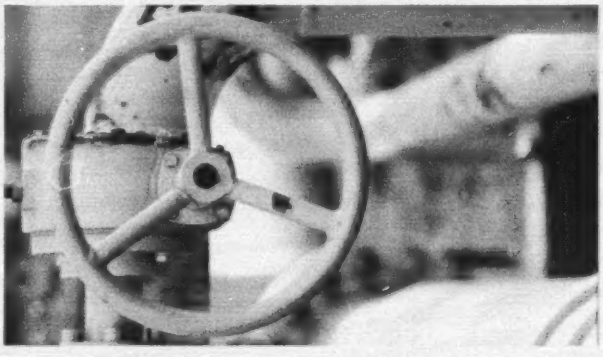
Resource revenue is estimated to increase by an average of 26 per cent per year between 2015-16 and 2017-18, to $4.37 billion, with substantial growth in bitumen royalties. The resource revenue forecast for 2017-18 is still less than half of actual 2014-15 revenue.

Real gross domestic product is estimated to contract one per cent in 2015 due to the collapse in oil prices and drop in energy investment. Corporate profits and Alberta government revenue "will be hit particularly hard by the weaker outlook for oil prices," the province noted in its budget. The economy is forecast to expand in 2016, but at a relatively slow pace of 0.9 per cent, reflecting the lagged effects of lower oil prices on employment, housing and consumer spending.

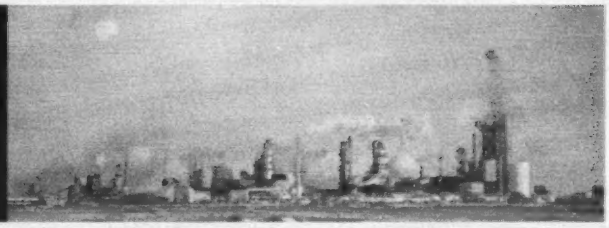
In 2017 and 2018, growth is expected to accelerate to around 2.5 per cent, supported by gradually rising oil prices, weaker cost pressures, a stronger U.S. economy and a low Canadian dollar.

"Energy is going to be Alberta's business and the heart of our economy and our economic development for many decades to come," said Finance Minister Joe Ceci during his budget speech. "But jobs and diversification must also be at the top of our agenda this year and every year from now on.

"Albertans are well aware that the recent drop in the price of oil is presenting our province with a serious challenge." ■



WHAT'S NEW IN THE OIL & GAS INDUSTRY



INDUSTRY AWAITS RESULTS OF PROVINCIAL ROYALTY REVIEW

There is a "fine line" in terms of finding the right royalty rate balance, and if the government gets it wrong, then the unintended consequences could result in fewer jobs and less tax revenue for the province, suggests Murray Edwards, chairman of Canadian Natural Resources Limited.

"I don't believe there is a lot of room in the royalty system for change in economic parameters," he said at the recent Bennett Jones Lake Louise World Cup Business Forum.

During his presentation, Edwards noted that in 2011 the British government instituted royalty and fiscal changes, which he believes came at a high cost for North Sea investment and resulted in 19 per cent production declines, year over year, versus a traditional six per cent decline.

"As a result of increased royalties, the government actually had fewer jobs and generated £2.3 billion less tax revenue than they had forecast."

Alberta royalties are already "somewhat high" compared to nearby jurisdictions, and so any changes to the regime must maintain the province's competitiveness, Edwards said. "I think there is change-opportunity for simplification of the system. I think there is opportunity in the system to address where some of the...challenges are."

Earlier this year, the provincial NDP government announced a royalty panel that would consult with Albertans, industry and all stakeholders in order to provide feedback to the government, which would aim to make some "preliminary conclusions" before the end of the year.

Peter Tertzakian, panel member and speaker at last week's forum, said the review process is on schedule and would be making recommendations prior to the new year, although he does not know the exact date. After personally consulting with about 300 people, he told the forum, a common opinion he has found is that the current structure definitely requires at least some changes.

"I look at it and can tell you that it is out of date. It is based on technologies that had their limit five years ago, and that is the last time that it was looked at. It is complicated—way too complicated—and it has what are called 'distortions,' and it does not give the right incentives to go after the highest-value products.

"It is not transparent. It is ephemeral. For the programs that expire, how is that supposed to bring any sort of certainty in what we are supposed to be doing going forward? You don't even know what your royalty rate is until you hit a commodity. It could be anywhere from 10 to 40 per cent. There are people out there scared to drill a well because they don't know what their rates are going to be."

REGULATOR'S DECISION GIVES COS BREATHING ROOM

Canadian Oil Sands Limited shareholders have until Jan. 4, 2016, to reject or accept Suncor Energy Inc.'s takeover, an Alberta Securities Commission (ASC) panel ruled Nov. 30, in a compromise between the two companies who were both playing "hardball," according to the regulator.

Considering it to be in the public interest, the ASC panel issued an order cease-trading the COS 2015 shareholder rights plan, effective at 6 p.m. on Monday, Jan. 4, 2016.

Suncor had applied to cease-trade a shareholder rights plan implemented by the board of directors of COS in October that required bids to be open for 120 days, saying shareholders should have more time to consider the offer.

Because Suncor's offer was open for acceptance only until Dec. 4, (unless extended or withdrawn by Suncor), it would not be a permitted bid under the new rights plan.

"We accept that additional time after the end of this week will be useful and perhaps necessary for the process to do its work in the interest of COS shareholders," said Stephen Murison, hearing chairman.

On Dec. 3, Suncor announced that it would extend its offer to COS shareholders. Suncor filed a corresponding notice of extension to formally extend the expiry time of its offer to 6 p.m. MT on Friday, Jan. 8, 2016.

"Our offer is full and fair and in the best interests of COS shareholders," said Steve Williams, Suncor's president and chief executive officer. "This process has always been about allowing COS shareholders to decide for themselves on the merits of our offer. The good news is that they will finally have their say."

The ASC panel, consisting of Murison, and Fred Snell, heard submissions from Suncor and COS lawyers and financial advisors during the two-day hearing last week.

Murison noted both parties took very different positions, some of them expressed in forceful terms and said neither party has acted improperly.

"These are serious matters with important consequences, but they are matters on which intelligent and reasonable ➤

WHAT'S NEW IN THE OIL & GAS INDUSTRY CONTINUED

parties can and obviously do differ. Both sides are involved in a serious contest and both are playing hardball—Suncor by launching a hostile takeover bid...COS and its directors by responding with a new [shareholders rights] plan. Hardball is allowed," said Murison.

Part of Suncor's argument for not allowing COS more time to find alternate bidders was that COS had been slow at developing alternatives to Suncor's bid and that it had raised little interest, but the ASC panel didn't agree.

COS has said 25 companies have expressed interest and four have signed confidentiality agreements.

ALBERTA LAND SALES CONTINUE TO DECLINE

Following a strong Nov. 18 sale, the Alberta government returned to weaker land sales with a $3.07-million auction on Dec. 3.

Industry purchased the rights to 26,987 hectares at an average price of $113.92.

That brings the year-to-date total to $286.17 million at an average price of $183.80—which is at least a 20-year low, according to *Daily Oil Bulletin* electronic data that dates back to 1995. Industry has purchased the rights to 1.56 million hectares at the nine-month mark.

To the same point of 2014, the government had collected $453.7 million for 965,111 hectares at an average price of $470.11.

The province's land sales this year have produced some very low bids, with the lowest average price of $45.86 occurring at the May 27 sale.

According to Alberta Energy, the minimum bonus amount is $2.50 per hectare for a lease and $1.25 per hectare for a licence. A bid request includes the $625 agreement application fee, the first year rental of the agreement of $3.50 per hectare or $50 (whichever is greater) and a bonus amount (the amount being paid to acquire the rights to the agreement).

A royalty review is currently ongoing in Alberta, and land sales are being reviewed as part of this work, said the panel chairman.

"Yes, our review looks at total [government proceeds] which includes land sales," Dave Mowat, president and CEO of ATB Financial, said. "The system is designed to flex in low prices [lower royalty rates and land sales] and take...higher royalties and land sales when prices are high. All the components are incorporated in the design and are combined when comparing our fiscal regime with others."

PEMBINA PIPELINE APPROVES RECORD $2.13-BILLION BUDGET FOR 2016

Pembina Pipeline Corporation has set its 2016 capital program at a record $2.13 billion, up from estimated 2015 spending of $1.9 billion.

Planned spending includes $1.38 billion for conventional pipelines, $485 million for midstream, $115 million for gas services, $115 million for oilsands/heavy oil and $35 million for other purposes.

The 2016 capital program is primarily directed towards progressing various multi-year projects, which are largely underpinned by long-term, fee-for-service contracts, said Mick Dilger, Pembina president.

Projects to be commissioned in 2016 include the company's second Redwater fractionator, two large gas plants, the Horizon Pipeline expansion, the Vantage Pipeline expansion and other smaller projects across each of its business units.

PEYTO ESTIMATES 2016 BUDGET OF $600 MILLION TO $650 MILLION

Peyto Exploration & Development Corp. has approved a preliminary 2016 capital budget of $600 million to $650 million, which includes drilling between 130 (124 net) and 145 (137 net) horizontal wells.

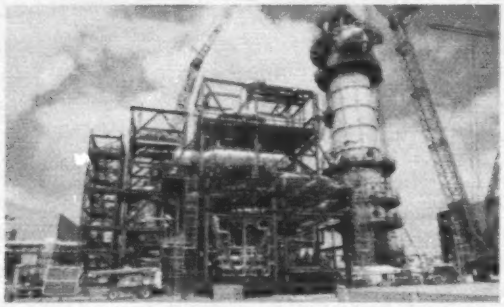
By comparison, for this year the company's expected capital budget is between $575 million and $625 million, which suggests that Peyto intends to spend as much, if not more next year, while many other companies are trying to reduce spending.

"We tend to 'zig' when the industry is 'zagging,'" Darren Gee, president and chief executive officer, told the company's third-quarter conference call. "In this particular environment, for instance, we are starting to invest quite aggressively while the industry is really dialling back a lot of its activity.

"That is because we know the key to generating better returns for our shareholders is to spend less in developing our reserves and production, and when the industry isn't busy... everything costs less."

Facility and pipeline investments of up to $85 million for next year will strengthen and expand the company's wholly owned and controlled infrastructure, management says, resulting in a 15,000-boe/d capacity increase. Spending will include a $50 million investment in expansion of existing gas plants at Swanson and Brazeau. ■

TECHNOLOGY UPDATE



COST REDUCTIONS NEXT STEP FOR SHELL QUEST CCS PROJECT

With its $1.35-billion Quest carbon capture and storage (CCS) project north of Edmonton now deemed commercial-scale, Royal Dutch Shell plc will be turning its attention to finding ways to reduce costs, says the project lead.

"One of the key reasons we did Quest was to really exploit the lessons we can get from building and operating this to try to bring down our operating and capital costs," Tim Wiwchar said. Operating costs are about $40 per tonne for the world's first oil sands carbon capture and storage project, which also is Shell's first commercial-scale CCS project.

The key focus will be on evolving technologies that are cheaper but provide even more security as determined by the project's measurement monitoring and verification program, along with reducing power or steam costs at the Scotford refinery, he said.

The project initially will capture one million tonnes per year of carbon dioxide—about one-third of the refinery's total emissions. The CO_2 is then transported via an 80-kilometre pipeline to the Thorhild, Alta., area where it is injected into an underground reservoir.

The largest part of the cost (about 80 per cent) for Quest is that of carbon capture, typically at source, that involves a lot of the large vessels, piping, pumps and compressors, while the remaining 20 per cent of the capital cost is the pipeline and injection wells.

"We are looking at a new type of amine that requires a smaller size of vessel or lower operating pressures, or even how we develop the reservoir to reduce the back pressure, and hence the size of it."

Some of the cost reduction will occur through replication. "You have done all the engineering work before you have done the tweaks, so you can reduce some of your upfront costs."

Economies of scale will also contribute to further cost reductions.

DIGITAL OILFIELD: OPPORTUNITIES AND CHALLENGES

A research study conducted by JuneWarren-Nickle's Energy Group and commissioned by GE Canada and Accenture presents a favourable assessment of the implementation of digital oilfield technologies even in budget-constrained times.

The report, *Digital Oilfield Outlook Report: Opportunities and Challenges for Digital Oilfield Transformation*, posits that the digital oilfield offers a remedy for slumping oil and gas prices with proven and adaptable technologies enabling considerable efficiency within Canada's oil and gas field operations.

View a copy of the report.

FORMATION FLUID TECHNOLOGY IN MARKETING AGREEMENT WITH CLEAR ENVIRONMENTAL SOLUTIONS

Calgary-based Formation Fluid Technology Inc. (FFT) has entered into a marketing agreement with Clear Environmental Solutions, a division of Canadian Energy Services & Technology Corp.

Clear and FFT will market certain of each other's services to existing and new clients.

"Clear has great relationships with a significant number of intermediate and major oil companies," said FFT's CEO Ken Rose. "Exposing our Hydro-cycle system to these customers gives those companies the ability to clean and re-use produced and frac flow backwater, which can provide large economic benefits.

"Using the Hydro-cycle system can save oil companies over 50 per cent of their water management costs and significantly reduce the amount of water taken from the environment."

FFT and Clear have worked together on a past project and are now formalizing a mutually beneficial relationship going forward. ■

LABOUR UPDATE

DEMAND FOR SKILLED WORKFORCE REMAINS STRONG

The growing technical and business complexities of Canada's oil and gas industry, together with the need to remain competitive internationally, is driving demand for a more skilled and knowledgeable workforce, according to a report released by the Petroleum Labour Market Information (PetroLMI) Division of Enform.

The report, *HR Trends and Insights: Shifting Priorities and a Shifting Workforce*, examines three key business shifts that Canada's oil and gas industry has witnessed in recent years: new technologies designed to access harder-to-reach reserves, cost-management strategies intended to simultaneously improve returns and productivity, and the need to diversify into new and expanded markets.

"With these three significant shifts has come the need for new and more intricate skills as well as different occupational requirements. The worker of today is quite different than the one from a decade or more ago. New entrants need to be more familiar with technology of all types," says Carol Howes, vice-president of communications and PetroLMI, Enform.

"Many of today's workers require business acumen and negotiating skills. And, with an increased focus on building new infrastructure, safety and environmental issues, comes requirements for more specialists such as those in well abandonment and reclamation, or stakeholder and Aboriginal relations."

According to the report, the ability to tap into unconventional reserves using innovative technology has significantly altered the types of equipment, materials and services now required to support much of Canada's oil and gas development. Likewise, the need to balance performance with cost reductions calls for more supply chain and logistics specialists as companies centralize supply chain management to realize economies of scale. Similarly, in its desire to reach new offshore markets, the industry will require a workforce with a new set of skills and knowledge in liquefied natural gas.

Many of today's oil and gas workers must be highly skilled at reading, numeracy, communicating and problem solving. They may have to plan and execute projects of all sizes and understand the cost implications or the regulatory requirements, notes the report.

DESPITE THE DOWNTURN, EMPLOYEE TRAINING AND PROFESSIONAL DEVELOPMENT REMAIN KEY

Cuts to training and professional development budgets for employees during the downturn could save oil and gas companies money in the short term, but cost them a lot more in the long-term, warns a Calgary recruitment consultant.

"The skills shortage is going to be exacerbated when we come out of this downturn and [companies] are not doing what they can to help themselves upskill their workforce that is going to be with them," says Jim Fearon, vice-president, central region for Hays Canada, part of a global recruiting firm.

In its sixth annual salary guide, Hays found that only two per cent of those surveyed are taking any additional measures to enhance the skills of their staff even though 57 per cent of respondents believe the industry suffers from a moderate to extreme skills shortage due to a lack of training and development.

Conducted in October 2015, the Hays salary guide highlights employer confidence, a look at business expectations versus results, and a snapshot of hiring trends and challenges.

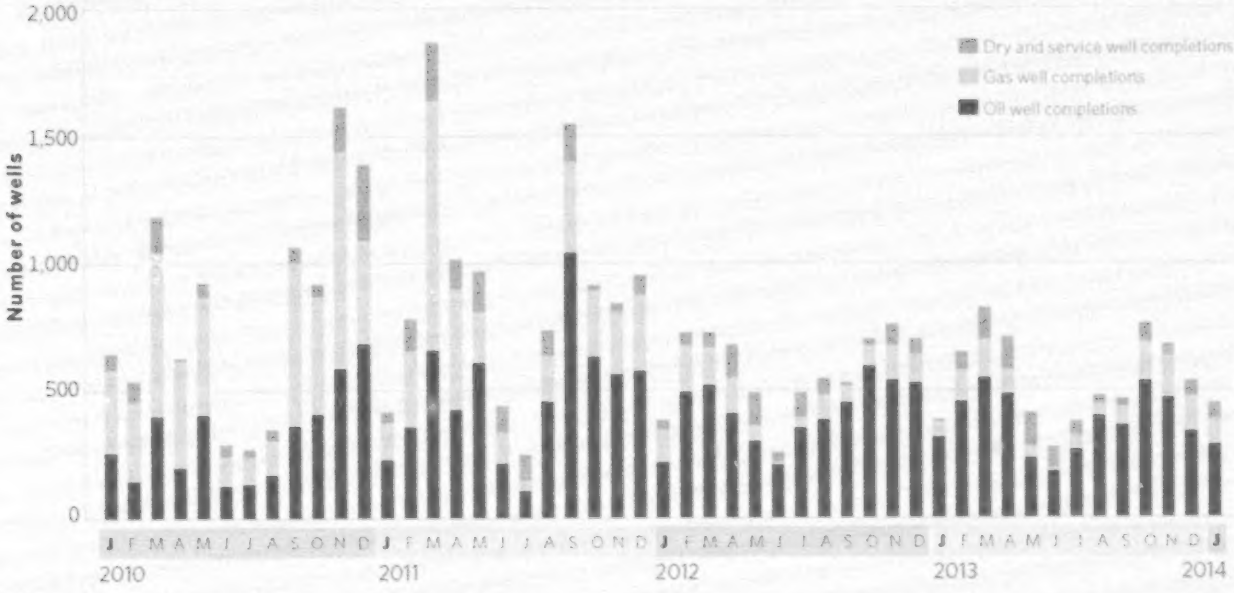
"One of the big opportunities that I think is going to get lost is that so few companies in the industry invest in training and developing their own staff," says Fearon.

"The downturn is an opportunity to upskill your existing staff. You are not hiring new people and maybe you are making layoffs but can you invest some time and money in developing the...skill set of your existing staff?"

Companies that do so, Fearon suggests, will find that when the market recovers and starts to pick up, they will have people with greater capabilities and capacities and a greater understanding of the business who may be able to step up into more senior roles. ■

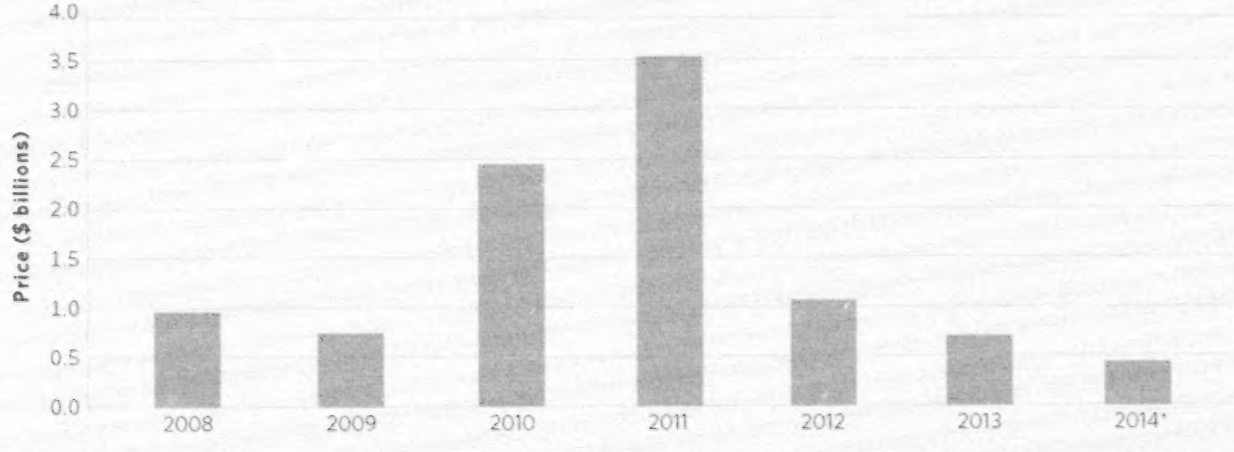
OIL & GAS STATISTICS

ALBERTA WELL COMPLETIONS


2,000
1,500
1,000
500
0
Number of wells
Dry and service well completions
Gas well completions
Oil well completions
J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J F M A M J J A S O N D J
2010
2011
2012
2013
2014

ALBERTA CROWN LAND SALES

Petroleum and natural gas rights, excluding oil sands



STATISTICS CONTINUED

DRILLING RIG COUNT BY PROVINCE/TERRITORY

December 1, 2015

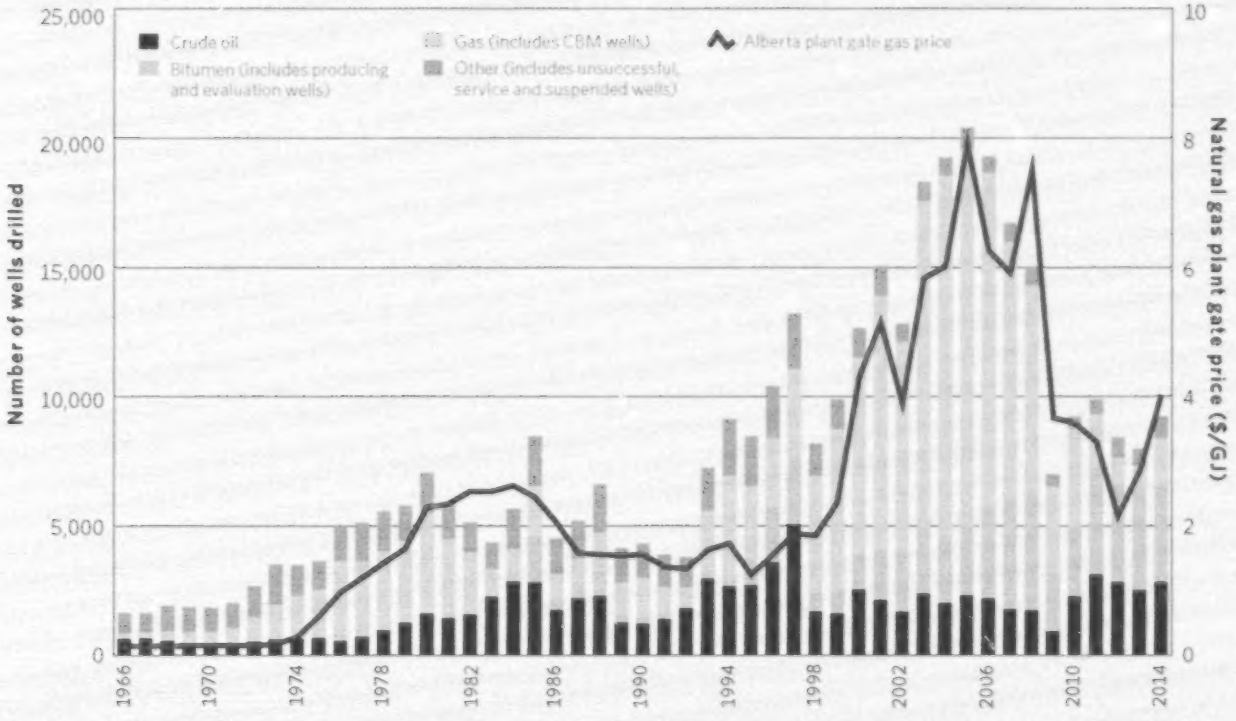
	ACTIVE	DOWN	TOTAL	ACTIVE
Western Canada				(Per cent of total)
Alberta	119	416	535	22
Saskatchewan	34	99	133	26
British Columbia	34	48	82	41
Manitoba	3	10	13	23
WC total	**190**	**573**	**763**	**25**
Eastern Canada				(Per cent of total)
Quebec	0	1	1	0
Canada total	**190**	**574**	**764**	**25**

OIL AND GAS WELL COMPLETIONS BY PROVINCE

November 2015

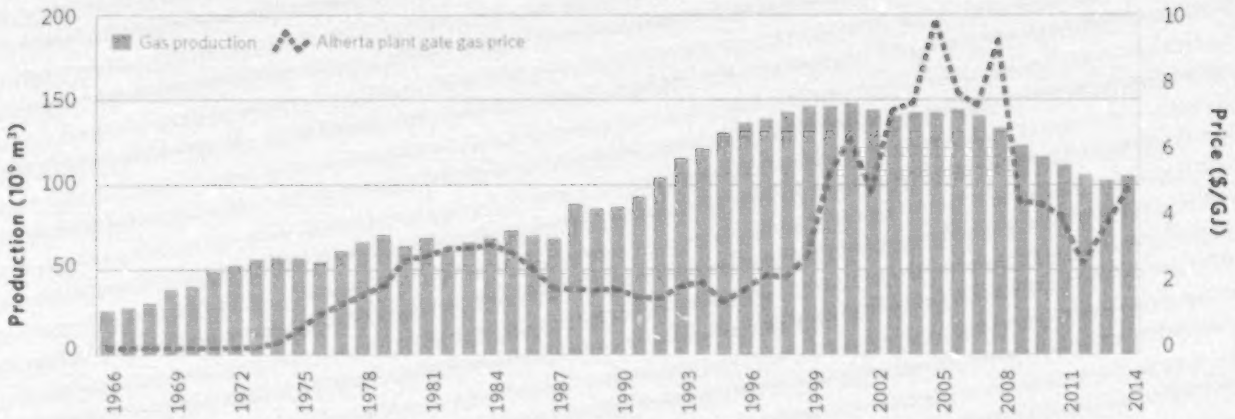
	OIL WELLS		GAS WELLS	
Western Canada	NOV '14	NOV'15	NOV'14	NOV '15
Alberta	355	152	196	93
British Columbia	4	8	58	84
Manitoba	40	9	0	0
Saskatchewan	307	94	2	0
Total	**706**	**263**	**256**	**177**

DRILLING ACTIVITY IN ALBERTA, 1966-2014

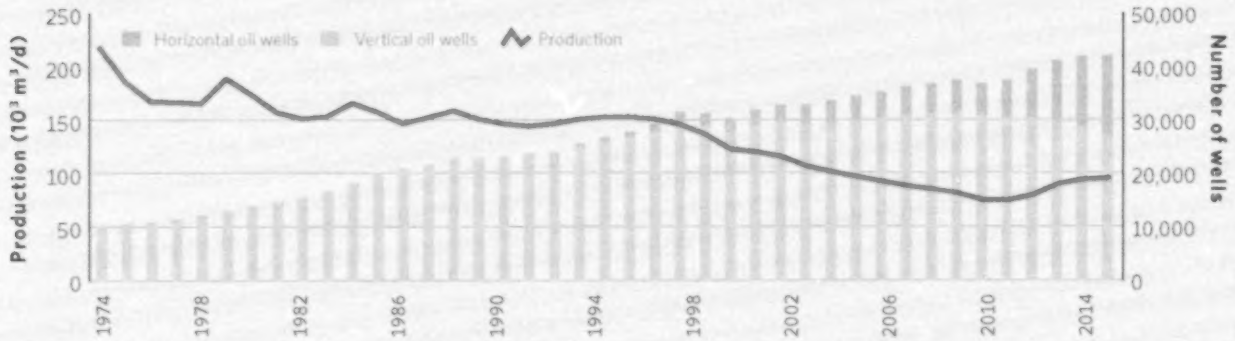


STATISTICS CONTINUED

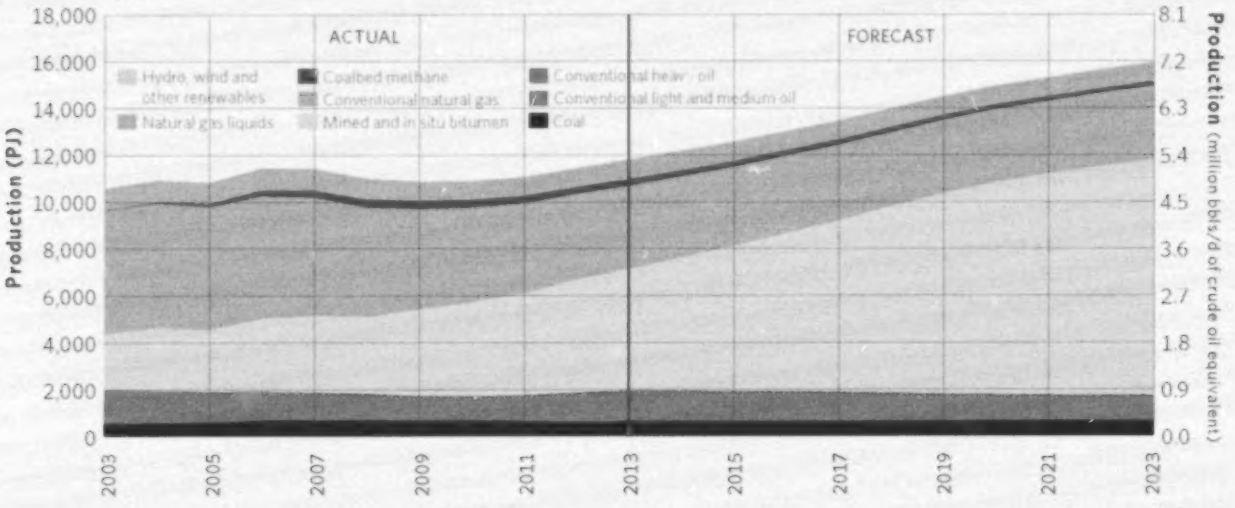
ALBERTA MARKETABLE GAS PRODUCTION



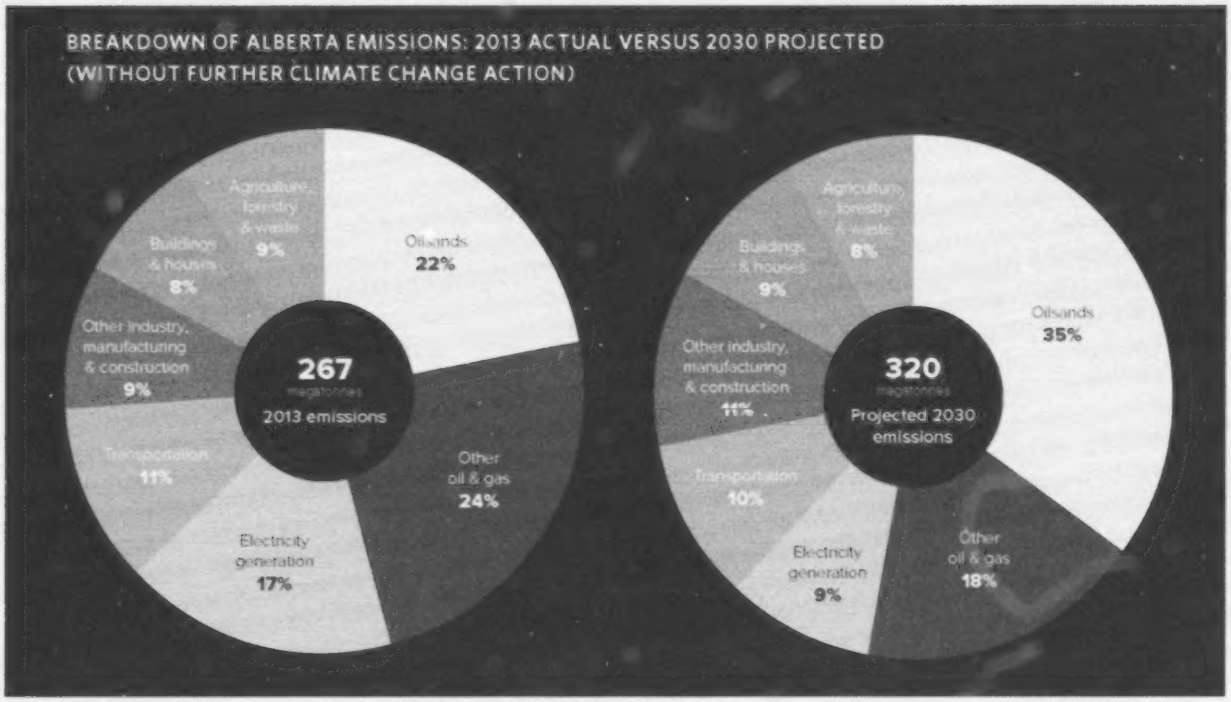
ALBERTA CRUDE OIL PRODUCTION AND PRODUCING WELLS



TOTAL PRIMARY ENERGY PRODUCTION IN ALBERTA



THE **ENVIRONMENTAL** FILE


BREAKDOWN OF ALBERTA EMISSIONS: 2013 ACTUAL VERSUS 2030 PROJECTED
(WITHOUT FURTHER CLIMATE CHANGE ACTION)
Agriculture, forestry & waste 9%
Oilsands 22%
Buildings & houses 8%
Other industry, manufacturing & construction 9%
267 megatonnes 2013 emissions
Transportation 11%
Other oil & gas 24%
Electricity generation 17%
Agriculture, forestry & waste 8%
Buildings & houses 9%
Oilsands 35%
Other industry, manufacturing & construction 11%
320 megatonnes Projected 2030 emissions
Transportation 10%
Other oil & gas 18%
Electricity generation 9%

Source: Daily Oil Bulletin

INDUSTRY SHOWS INITIAL SUPPORT FOR NEW CLIMATE CHANGE PLAN

Oil and gas industry reaction to the Alberta government's new climate change strategy is generally positive and shrouded in guarded optimism; however, sector leaders say more concrete details need to be fleshed out before the true ramifications of the plan are known.

The Rachel Notley-led NDP government unveiled its climate change management strategy Nov. 22, 2015, an ambitious plan that includes a legislated emissions limit on the oil sands, a carbon price across all sectors and pledges to reduce methane emissions from oil and gas operations.

With prominent representatives from industry and the environmental movement in tow, Notley said the plan will set up the province and energy industry for future growth.

"It will help us access new markets for our energy products and diversify our economy with renewable energy and energy efficiency technology," Notley said in Edmonton. "Alberta is showing leadership on one of the world's biggest problems."

Tim McMillan, president of the Canadian Association of Petroleum Producers, said the Alberta Climate Leadership Plan provides direction that will allow the province's oil and natural gas industry to grow, further enhance its environmental performance through technological innovation, and is expected to improve market access.

"It was a very aspirational and directional announcement, and there are going to be a lot of details that are yet to be defined and that will matter a great deal," McMillan told the *Daily Oil Bulletin*.

"We are supportive of linking these policy changes with market access; that there's a commitment from government that market access is a crucial part in moving our industry and province forward."

Gary Leach, president of the Explorers and Producers Association of Canada, agreed that the climate management plan is a step in the right direction, noting that it formed the basis of the province's platform at the international climate change conference in Paris.

"Although the government says it will consult with Albertans about this report, it is likely to be adopted with few, if any changes, and will permanently re-orient the oil and gas and electric power industries," he said.

Leach added that "an impressive line-up of industry leaders, Aboriginal groups and environmental NGOs, who rarely seem to be on the same page," were brought together by the government to signal their support for the report's recommendations.

"Alberta has a lot riding on whether this big change of direction will mute opponents of the oil and gas industry and deliver the new market access that our industry needs for our energy exports," he said. ■

FOCUS ON THE **DUVERNAY**

For more on the Duvernay, see the *Daily Oil Bulletin*'s special digital magazine of the play.

ENCANA'S DUVERNAY WELLS CONTINUE TO IMPRESS

Encana Corporation says it continues to make significant progress in the Duvernay.

During the company's third-quarter conference call Nov. 12, president and CEO Doug Suttles said the Duvernay program in the Alberta Deep Basin continues to make significant strides in both well performance and efficiency gains.

"A lot of these wells are plus one million [barrels of oil equivalent]—1.1 million [barrels of oil equivalent] type curves and they're about half condensate and half gas. Some can be bigger," he said.

"In the Duvernay's case we actually talk about the north and south Simonette. The north has a bit lower cost and a smaller type curve, and the south has a higher cost but bigger type curves because it's much higher pressure."

Mike McAllister, Encana's chief operating officer, added that "the Duvernay works and it's becoming material." He said that the company's innovative approach to exploiting the play is successfully driving down well costs and increasing productivity.

"In the quarter we achieved a new benchmark completion costs of $6.4 million per well. Our water hub reduced our water handling costs by $1.2 million per well," he said.

McAllister said that Encana has brought on five new wells at Simonette south and that those wells are averaging 1,200 barrels per day (bbls/d) of condensate and six million cubic feet per day (mmcf/d) of natural gas at a flowing pressure of 6,000 psi.

"These top percentile wells are the result of our unique approach to development of this play. Our approach utilizes dual drilling rigs, dual frac crews, targeted laterals, high-intensity completions and our water infrastructure," McAllister said.

During the third quarter, the company repeated its industry-leading Duvernay drilling and completion costs of $10.4 million per well on the 15-22 multi-well pad. It also brought the 15-31 compressor station online, increasing processing capacity by 10,000 bbls/d and 50 mmcf/d.

Encana drilled two net Duvernay wells in the third quarter and brought seven net wells on production.

Third-quarter Duvernay production of 9,300 bbls/d was up 59 and 69 per cent from the second and first quarters, respectively.

The company expects to drill five net wells and bring six on production in the Duvernay in the fourth quarter and is on track to deliver fourth-quarter production of 17,000 barrels of oil equivalent per day.

DUVERNAY SHALLOW CUT GAS PLANT NEAR FOX CREEK PLANNED BY PEMBINA PIPELINE

Pembina Pipeline Corporation says it plans to construct, own and operate the first large-scale gas plant designed specifically for the Duvernay play with a new 100 mmcf/d shallow cut plant near its Fox Creek terminal.

The expected capital cost for Duvernay I, including supporting infrastructure, is expected to be roughly $125 million. Subject to regulatory and environmental approval, it should be in service in the second half of 2017.

"The design of the plant will closely resemble that of our Musreau II and III expansions, giving us confidence of being able to execute the project on time and on budget," Mick Dilger, Pembina president and chief executive officer, said this morning in a conference call to discuss third-quarter 2015 results.

"This project exemplifies the value of Pembina's integrated service offering and will create a platform for growth in the Duvernay," he said. The facility is underpinned by a long-term, take-or-pay agreement with a large diversified oil and gas customer who also has executed agreements for volumes in Pembina's pipeline expansion and fractionation facilities at Redwater.

Pembina expects the plant to have approximately 5,500 bbls/d of natural gas liquids extraction capacity, subject to gas compositions. Production from the facility will be transported on Pembina's Peace Pipeline system under a long-term, take-or-pay agreement.

These incremental volumes serve to further enhance Pembina's Peace Phase III expansion project, which is expected to provide 420,000 bbls/d of incremental liquids transportation capacity from Fox Creek to Namao (subject to regulatory approval). ■

CONTACTS

INDUSTRY ASSOCIATIONS

Alberta Land Surveyors' Association www.alsa.ab.ca
Canadian Association of Geophysical Contractors www.cagc.ca
Canadian Association of Oilwell Drilling Contractors www.caodc.ca
Canadian Association of Petroleum Producers www.capp.ca
Canadian Energy Pipeline Association www.cepa.com
Canadian Gas Association www.cga.ca
Canadian Natural Gas www.canadiannaturalgas.ca
Canadian Natural Gas Vehicle Alliance www.cngva.org
Canadian Society of Exploration Geophysicists www.cseg.ca
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Petroleum Technology Alliance Canada www.ptac.org
Explorers and Producers Association of Canada
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